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Infill Drilling for Shale Gas Development: A Field Case Study

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ABSTRACT

The U.S. Department of Energy has conducted a reservoir simulation study of a producing Devonian shale reservoir in Meigs Co., Ohio, following an extensive field testing program[1] to determine the parameters controlling production from this unconventional gas resource. The purpose of the study was to determine the possible impact of infill drilling in established areas of Eastern gas shales production. A dual porosity reservoir simulator that was developed especially for shale gas formations was used in the study.

The simulation study applied the results of the previous field test program to history match the production from shale gas wells located near the test site in Meigs County, Ohio. A series of 70-year simulations showed that by infill drilling now, 35 years after the completion of the discovery well, cumulative production can be increased by 30 percent or more. Had the closer well spacing been implemented at the earliest possible time, cumulative production over the 70-year period could have been increased by 60 percent or more.

INTRODUCTION

Recent studies by the United States Geological Survey estimate the in-place gas resource of the Appalachian Basin Devonian Shales to be 577 Tcf to 1100 Tcf[2]. 85-160 Tcf of this resource is located in areas of historical shale gas production. As of 1976, approximately 3 Tcf of this vast resource had been produced by about 10,000 wells[3]. While estimates place the current number of shale gas wells at approximately 12,000, the total gas production from the shales has probably not increased significantly. The gas recovery from existing fields could be increased by infill drilling to compensate for the preferential drainage pattern caused by permeability anisotropy. It has been advocated that infill drilling, combined with advanced stimulation technology could result in an increase in productivity of two to three times the current amount.

References and illustrations at end of paper.

Extensive research on the Devonian Gas Shales has been performed under the Department of Energy's Eastern Gas Shales Project (EGSP) for the past several years. Research efforts were implemented to characterize the nature of Devonian Shale reservoirs, to reduce the uncertainty of the resource basin, and to determine cost-effective extraction techniques.

As a part of the EGSP research efforts, an intensive field test was performed in Meigs County, Ohio, in 1981, to investigate the following reservoir parameters: (1) flow characteristics of gas in a fractured shale, (2) orientation and distribution of natural fractures, (3) storage and release mechanisms of gas from the shale, and (4) directional gas flow and its impact on production practices. The field test basically consisted of the drilling of two offsets to an existing base well, the extraction and analysis of cores and a series of closely-monitored production drawdown/buildup/interference tests on the three wells. Engineering analysis of the test combined the analytical results from the field test, laboratory data from core analysis, and simulation/ history matching of the complete test series and of the 23 years of base well production history.

Flow characteristics were observed and measured in the field and in the laboratory. It was shown that about 90 percent of the total gas production from each offset well came from a single zone (the Lower Huron Shale Member)[4]. A gas desorption value of 0.007788 scf/cu ft/psi was measured from laboratory core analysis. This amount of gas is equivalent to a free matrix porosity of about 11.4 percent. Reducing the desorption value to 0.007 scf/cu ft/psi gave good results in base well history matching. Simulation analysis showed that desorption was a contributing factor to the total production of the base well.

Porosities and permeabilities for the shale matrix were determined by core analysis. Fracture system properties were determined from the interference data, using a method of well test analysis for Devonian Shale wells developed at the University of Tulsa by Raj Raghavan, et al.[5]. These results were combined with history matching of the base well's 23-year production to come up with the best case fracture and matrix porosity and permeability values of 0.0009 (0.09 percent) and 0.07 md, and 0.01 (1 percent) and 0.25×10^{-6} md (0.00025 µd), respectively.

The analysis also revealed the importance of identifying an average fracture spacing for shale on an areal basis. As the natural fracture system serves as the gas transport medium, close average spacing of the fractures allows greater gas recovery. A deviated well program adjacent to the offset well site is currently addressing natural fracture spacing in the area, and determination of this average spacing on a region-wide basis is necessary for full characterization of the Devonian Shales. Simulation studies during the OWT analysis estimated the average fracture spacing in the Meigs County area to be 8 to 14 feet.

Also among the significant results of the analysis was the determination of anisotropic properties using interference data from the two offsets. Although a third offset well would be needed for absolute definition of a kmax/kmin ratio, the best solution, taking into account all other results from the analysis, was a ratio of 8.3 to 1[6].

BACKGROUND

The simulation study focused on a 15-well, 3,857-acre area in Chester, Orange and Olive Townships, Meigs County, Ohio (Figure 1). The study was conducted in cooperation with Columbia Gas, a major leaseholder in the area. Columbia operates the 15 gas wells producing from the Ohio shales. The first of these wells was completed in 1947, and completion of the others followed from 1956-1961. The wells, averaging 3000 feet in depth, were completed with perforated tubing throughout the shale, after borehole shooting an average 365-foot shale interval. Initial bottom hole pressure of the first well was recorded at 830 psia, and the initial reservoir pressure of the other 14 wells varied from 667 psia to 858 psia. After 20 to 35 years of gas production into 200 to 260 psia gathering lines, the bottom hole pressures in 1981 ranged from 274 psia to 627 psia. These pressure contours are shown in Figure 2.

MODEL APPLICATION

The study of the 15-well area involved extensive use of a new reservoir model developed specially for studying shale gas production. The new shale model simulates a naturally fractured gas reservoir and production performance from it. It depicts a dual porosity system in which gas is stored in the shale matrix (less permeable portion of the shale) and subsequently released into the natural fracture network, which provides a transport mechanism for the gas when linked to the borehole[7]. Substantiation of this mechanism was measured in the Devonian shale field test that is discussed in SPE Paper 11224 (New Orleans Meeting, 1982). Figure 3 is a representation of the model's depiction of the shale.

Two versions of the dual porosity model, a one-dimensional radial gas flow version and a two-dimensional version, were utilized. The radial flow version was used to simulate and history match single wells' production performance, while the two-dimensional version was used for the simulation and history matching of multi-well performance and the experimental placement of infill wells.

As this study made extensive use of history matching as a tool, a brief discussion of the uses and limitations of this technique is necessary. History matching consists of adjusting input parameters for a model until the simulated well or field performance is close to the actual historical performance. The first step in a history match is to calculate the reservoir performance using the best available data and to compare the simulated performance with the actual recorded history of the well or field. If the agreement is not satisfactory, adjustments must be made on input parameters until a match is achieved[8].

It is important to note that the behavior of a reservoir is influenced by many variables that cannot be determined precisely throughout a large area. History matching allows the determination of a set of parameters which give a calculated match. The combination is not unique, so it may not represent the exact conditions of the reservoir. However, when most of the parameters are substantiated by measurement (field or lab), history matching can be used to understand the importance of the parameters and their ranges on reservoir performance.

The matching of model predictions with the historical performance of a reservoir provides the only practical test of the validity of a reservoir model. The quality of a match and therefore the amount of confidence we can have in the model depends substantially on the amount of historical data available for the match[9].

SINGLE WELL ANALYSIS

History matching requires a base case set of data, the best available for a field. The best base case available for the commencement of the Meigs County history matches was the data set that was a result of the offset well test analysis. Formation of this set of model input data had combined field test results and laboratory findings to match pressure buildup and drawdown data and 23 years of production history. For this multi-well study, several input parameters from the field test analysis were assumed to be constant throughout the region. These values are shown in Table 1.

The radial flow model was used to history match the 15 individual wells, varying only the productive shale thickness and the fracture system permeability. With 20 to 35 years of historical data for each well, matches of rates and cumulative production were obtained. The individual history matching was necessary to obtain a base set of conditions for the study area which would account for variations in the production performance throughout the area. The resultant data sets provided the base case for beginning two-dimensional, multi-well simulations.

TWO-DIMENSIONAL AREAL INVESTIGATION

Initially for the two-dimensional simulations, a 31 x 31 block grid, covering 6.03 square miles (3856.75 acres) was applied to the study area. Each well was located in a 50-foot by 50-foot grid block, as shown in Figure 4, with the appropriate productivity index specified to relate average grid-block (fracture system) pressures to bottom-hole well pressures. Wellhead pressures and temperatures and well dimensions were input for the calculation of bottom-hole pressures.

Fracture system permeabilities and formation thicknesses which resulted from the single well history matches were contoured over the entire area, as had been done with the initial and latest formation pressures. The design of the grid layout over the field had placed the x-direction along the maximum permeability direction as determined by the prior field test analysis. Therefore, the permeability ratio (kmax/kmin) of 8.3 was applied to the contoured permeability values to obtain kx and ky values for each grid block, maintaining the geometric mean permeability from the original contour map. Thus, a value for fracture system permeabilities in the x and y directions, productive shale thickness, and initial reservoir pressure could be assigned to each grid block for the two-dimensional study.

Several attempts at simulating the entire 31 x 31 grid were made, using a mini-computer. Using an iterative solution technique (LSOR), convergence could not be reached, and when a direct solution technique (D4) was used, computer time was excessive. To reduce the computer time requirements to a reasonable value, a 19 x 9 grid portion of the field was selected for a smaller scale areal simulation. The area, outlined in Figure 4, is 8581 feet x 3751 feet (738.92 acres) and contains four of the existing wells, including the field test base well and the discovery well of the field.

Prior to simulating infill wells, it was necessary to match the performance of the four existing wells in the two-dimensional grid system. It was found that simulated production rates were considerably higher than in the single well simulations due to the permeability anisotropy and the lack of confinement as compared to the 52-acre areas (850-foot radius) used in the radial flow studies. In order to obtain a reasonable match of cumulative production from the four wells, the permeability level was reduced in a stepwise fashion, keeping the anisotropy ratio of 8.3. It was found that reducing kx and ky by approximately 80 percent resulted in a reasonable history match of the four well cumulative, as shown in Figure 5. Final kx and ky values ranged from 0.0395 md to 0.8490 md and from 0.0047 md to 0.1023 md, respectively, for the four-well study area.

SIMULATION OF INFILL WELLS

In order to evaluate the infill drilling potential in the area, seven cases were studied as illustrated in Figure 6. The intent was (1) to determine the impact on production of an infill drilling program now and (2) to compare results of drilling infill wells now with results of drilling additional wells early in the life of the field.

Placement of the infill wells is shown in Figure 4. The wells were placed in 50-foot x 50-foot grid blocks and spaced evenly through the four-well portion. Productivity indices were calculated for each new well using contoured values of formation thickness and permeability, and the completion method of each well was assumed to be the same as for the original wells. In Cases 2 and 3, infill well I-A was selected as the single infill well. Cases 4 and 5, with three infill wells, used wells I-A, I-B, and I-D.

RESULTS

Figure 7 shows a combined plot of the simulated 70-year production for infill drilling in 1981. The gain in production from infill drilling for all scenarios is compared to predicted four-well, 70-year production in Table 2. This suggests that much more gas could have been and can still be produced from the 739-acre, four-well portion by decreasing the average well spacing from 185 acres/well down to about 82 acres/well, the spacing if nine wells are placed in the small southern portion.

Trends of production increase from the three infill drilling cases illustrated in Figure 7 point out the need to characterize a reservoir prior to infill drilling. It can be seen that drilling one infill well greatly increased total production, but the drilling of three infill wells did not proportionally increase production, as might have been expected. It appears that this is caused by the placement of infill wells. Well I-A, the first infill well, is located in an area of high fracture permeability, as contoured from single well history matching results. Wells I-B and I-D were added for simulation of three infill wells. These two wells are located in areas of lower contoured permeability, thus the contribution from the two additional wells is not as great as from the single well. This illustrates the desirability to fully characterize a reservoir prior to development so that the placement of wells accounts for variations in field production performance caused by permeability anisotropy.

While the simulated drilling scenarios did show the potential for increasing the total gas production with closer well spacing, simulated gas remaining in the shale after 70 years was still considerable. Table 3 shows that, even with 84-acre spacing, only about 20 to 30 percent of the original gas in place is produced, regardless of when the additional wells are drilled. This shows a vast resource remaining to recover. This is notably different from earlier investigations of shale production potential which attempted to apply various other reservoir models for analysis of the shale gas resource. In early studies, gas production was assumed to be primarily from the natural fracture system, and recovery efficiency was estimated to be about 60 to 70 percent of the inplace gas volume after 30 years of production.

Figures 8, 9, and 10 illustrate apparently "lost" gas by comparing the drilling of additional wells at time zero to infill drilling after 35 years. Drilling the infill wells after 35 years results in a "loss" of 9 to 20 percent of the possible gas production compared to drilling the wells early in the life of the field. These differences are tabulated in Table 4.

CONCLUSIONS

Shale in the Meigs County, Ohio, area has historically produced only moderate quantities of gas. Even so, this simulation study has shown that infill drilling (approximate 84-acre well spacing in the established gas producing areas of Meigs County can result in greatly increased gas production over the next 35 years. This type of simulation study can be applied to areas of excellent and poor historical production so that the impact of infill drilling may be better quantified.

This area will, after 70 years of production, produce only 19 percent of the gas in place if the current well spacing of about 185 acres per well is maintained. This is largely due to the fact that most of the producible gas is held in the pores of the shale matrix. Additional wells early in the life of the field could have increased production by 23 to 60 percent. However, even after 35 years of production, infill wells can enhance gas recovery by 11 to 35 percent, depending on whether per well spacing is reduced to about 148 acres or 82 acres. Optimal development strategy requires an in-depth characterization of the apparent natural fracture trends, including permeability distribution and anisotropy, as the fracture transport mechanism is the key to shale gas production.

NOMENCLATURE

k_{max} = fracture system permeability in the maximum trend direction

k_{min} = fracture system permeability in the minimum trend direction

k_x = fracture system permeability in the x-direction

k_y = fracture system permeability in the y-direction

ACKNOWLEDGMENTS

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SI METRIC CONVERSION FACTORS

ft x 3.048*	E-01 = m
sq ft x 9.290 304*	E-02 = m^2
sq mi x 2.589 998	E+00 = km^2
acre x 4.046 873	E+03 = m^2
cu ft x 2.831 685	E-02 = m^3
scf x 2.863 640	E-02 = std m^3
psi x 6.894 757	E+00 = kPa

* Conversion factor is exact.

TABLE 1

SINGLE WELL ANALYSIS
MEASURED PARAMETERS HELD CONSTANT

Gas Desorption Rate	0.007 scf/psia/cu ft
Drainage Radius	850 ft
Fracture Spacing	10 ft
Matrix Porosity	.01 (1 Percent)
Matrix Permeability	.25 x 10^{-6} md
Fracture Porosity	.0009 (.09 Percent)

TABLE 2

SIMULATED EFFECT OF INFILL DRILLING ON FOUR-WELL, 70-YEAR CUMULATIVE PRODUCTION

Case	Description	Simulated Cumulative Gas Production at the end of 70 Years (MMcf)	Increase Over 4 Existing Wells (MMcf)	Increase Over 4 Existing Wells (Percent)	Gas in Place Recovered (Percent)
1	4 Existing Wells	1044.8	--	--	19.1
2	1 Infill Well at t = 0	1280.3	235.5	22.5	23.4
3	1 Infill Well at t = 35 Yrs	1167.0	122.2	11.7	21.3
4	3 Infill Wells at t = 0	1424.6	379.8	36.4	26.0
5	3 Infill Wells at t = 35 Yrs	1248.1	203.3	19.5	22.8
6	5 Infill Wells at t = 0	1676.0	631.2	60.4	30.7
7	5 Infill Wells at t = 35 Yrs	1396.0	351.2	33.6	25.5

TABLE 3

SIMULATED GAS IN PLACE AND GAS PRODUCED AFTER 70 YEARS

Calculated Original Gas in Place = 5510.2 MMcf
Percent in Fracture System = 0.87
Percent in Matrix as Free Gas = 9.70
Percent in Matrix as Adsorbed Gas = 89.43

Case	Description	70 Years of Production Percentage of Original Gas Produced: Total Resource	Free Matrix Gas	Adsorbed Matrix Gas
1	4 Existing Wells	19.1	21.4	18.6
2	1 Infill Well at t = 0	23.4	26.0	23.0
3	1 Infill Well at t = 35 Yrs	21.3	23.7	20.8
4	3 Infill Wells at t = 0	26.0	29.0	25.6
5	3 Infill Wells at t = 35 Yrs	22.8	25.6	22.4
6	5 Infill Wells at t = 0	30.7	33.3	29.7
7	5 Infill Wells at t = 35 Yrs	25.5	28.2	24.9

TABLE 4

COMPARISON OF DRILLING INFILL WELLS AT t = 35 YRS
TO DRILLING INFILL WELLS AT t = 0

Case	Description	Simulated Cumulative Gas Production (MMcf) 35 Years	70 Years	Increase Over Drilling Wells at t = 35 Years 35 Years	70 Years
2 vs 3	1 Infill Well at t = 0 vs 1 Infill Well at t = 35 Years	730.3 557.8	1280.3 1167.0	172.5 MMcf (30.9%)	113.3 MMcf (9.7%)
4 vs 5	3 Infill Wells at t = 0 vs 3 Infill Wells at t = 35 Years	816.0 557.8	1424.6 1248.1	258.2 MMcf (46.3%)	176.5 MMcf (14.1%)
6 vs 7	5 Infill Wells at t = 0 vs 5 Infill Wells at t = 35 Years	1009.8 557.8	1676.0 1396.0	452.0 MMcf (81.0%)	280.0 MMcf (20.1%)

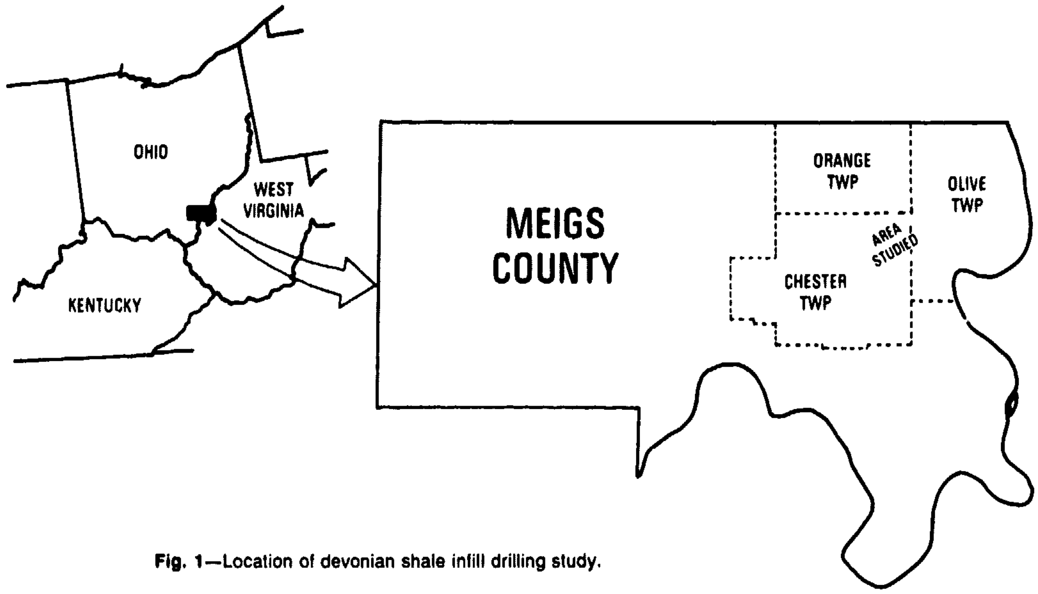

Fig. 1—Location of devonian shale infill drilling study.

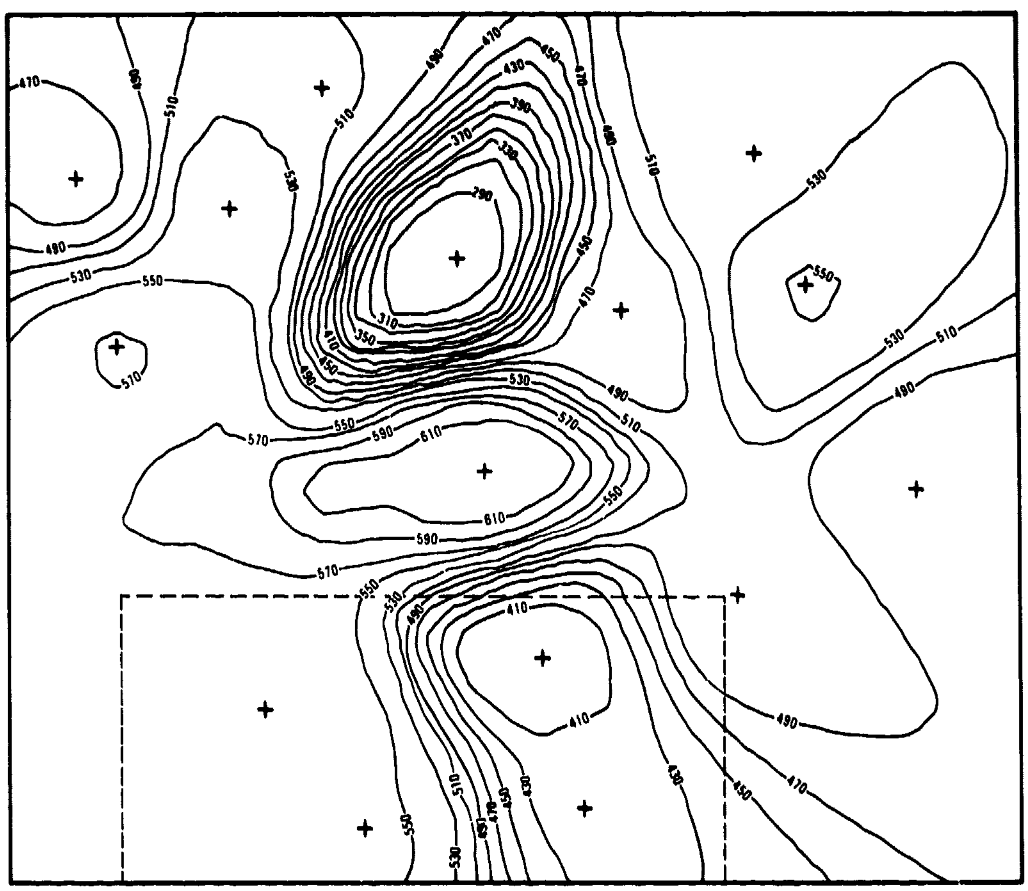

Fig. 2—Reservoir pressure distribution of 15-well study area after 20 to 35 years' production.

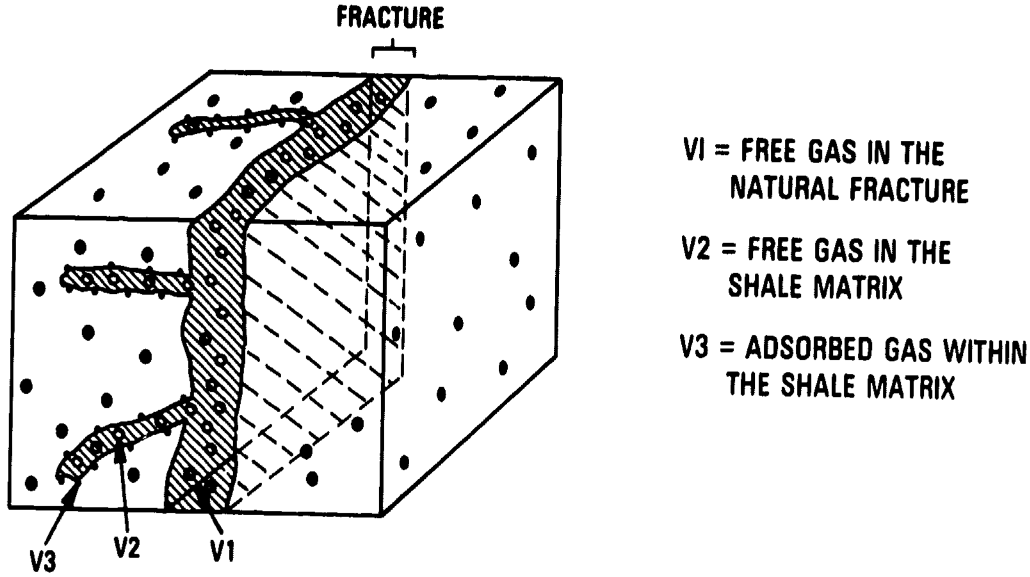

Fig. 3—Naturally fractured shale, as represented by shale reservoir model.

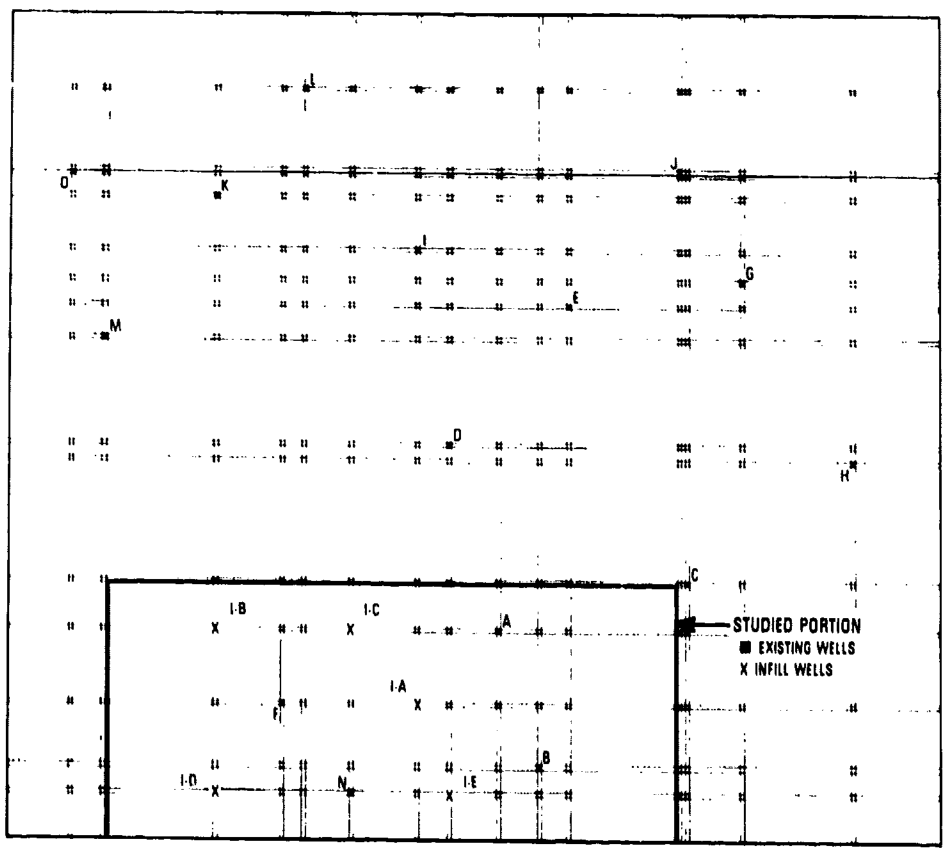

Fig. 4—15 well area grid-layout, showing four-well study portion, existing wells and simulated infill wells.

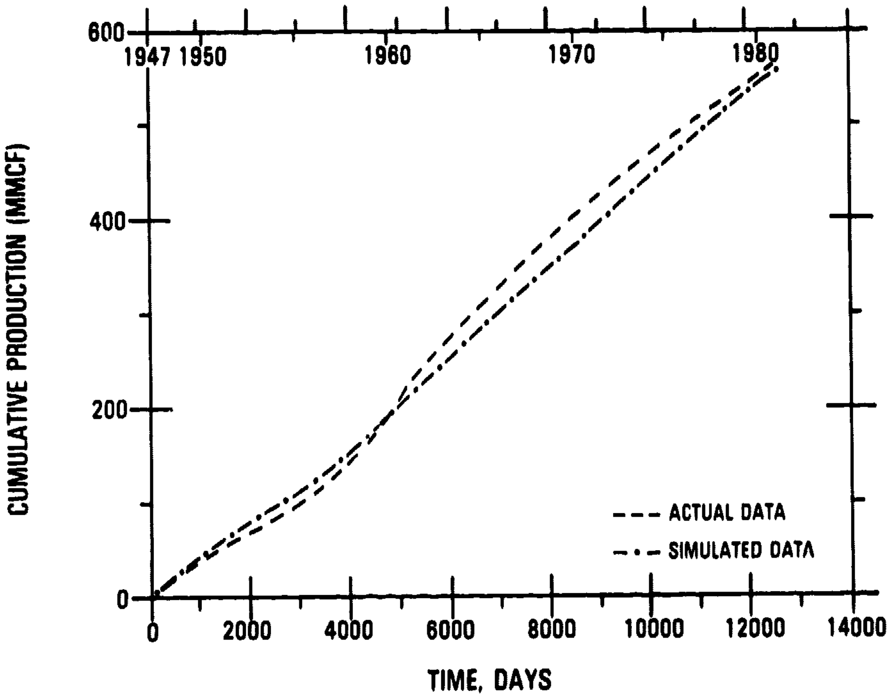

Fig. 5—35-year history match of four-well total cumulative production.

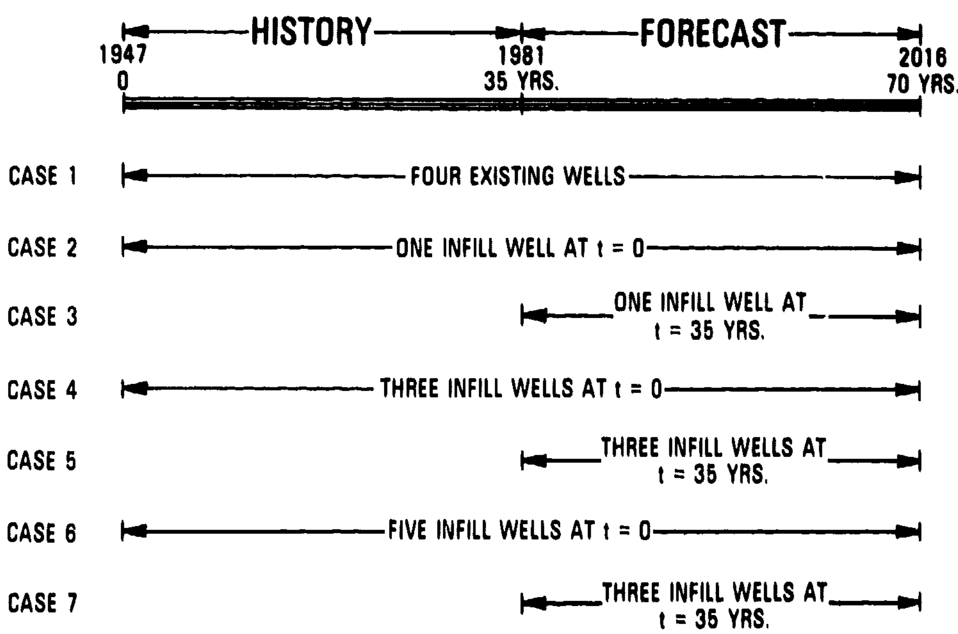

Fig. 6—Infill drilling scenarios investigated.

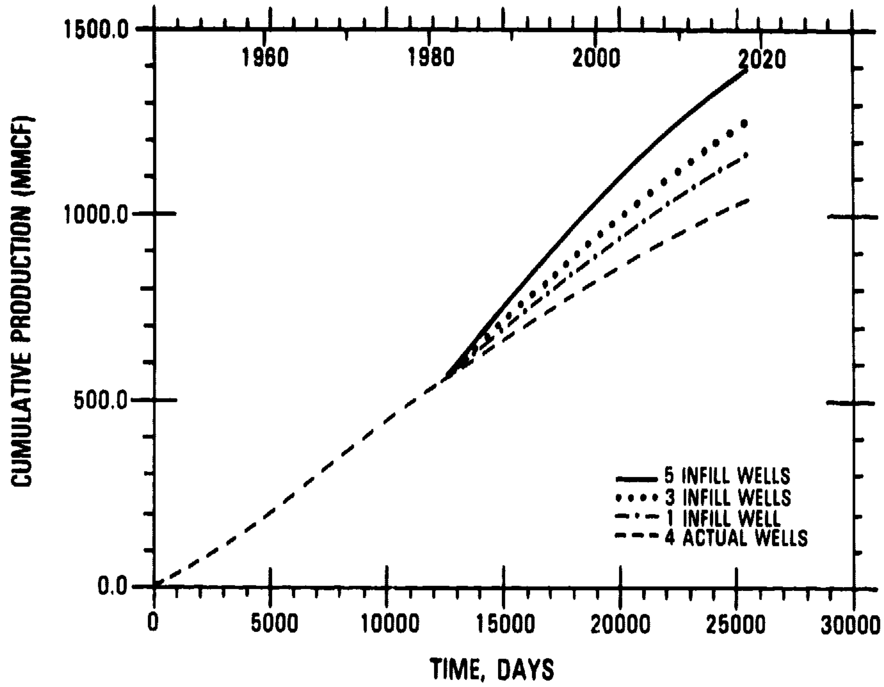

Fig. 7—70-year simulated cumulative production for four-well portion: effect of infill wells drilled after 35 years of production.

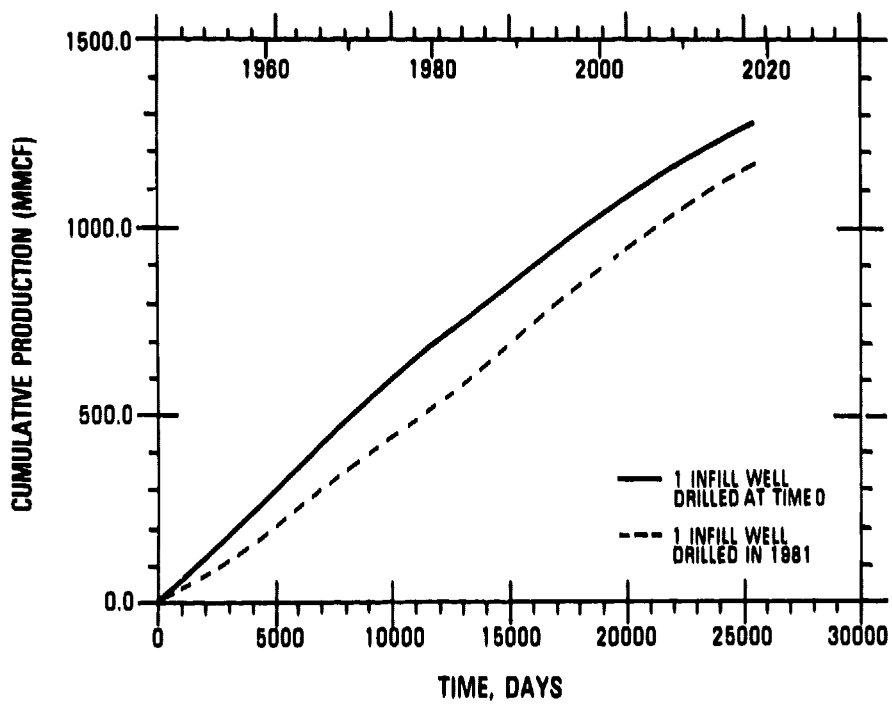

Fig. 8—Impact of 1 additional well on four-well portion's 70-year production: infill drilling at $t=0$ vs. $t=35$ years.

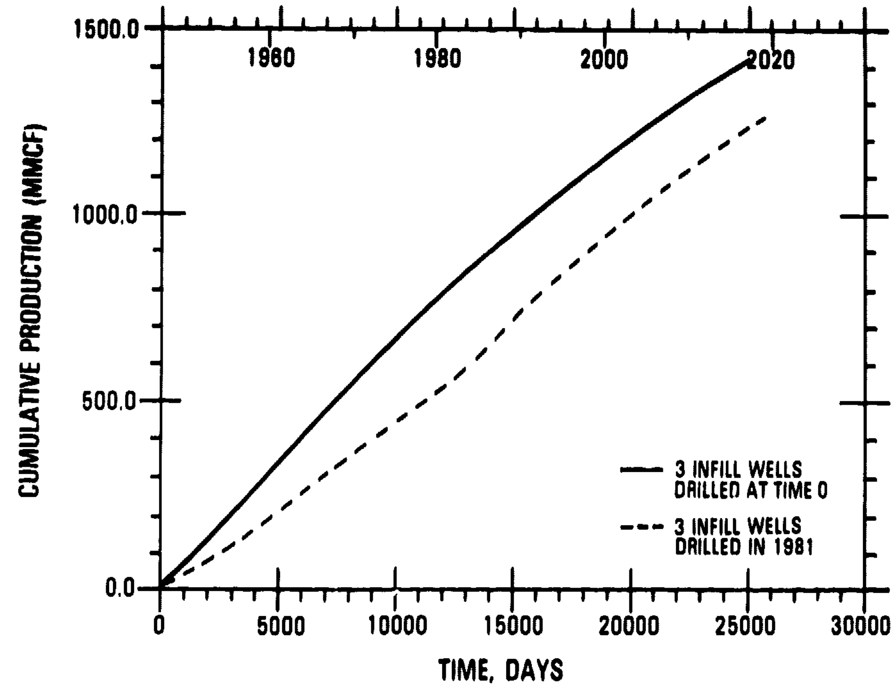

Fig. 9—Impact of three additional wells on four-well portion's 70-year production: infill drilling at $t=0$ vs. $t=35$ years.

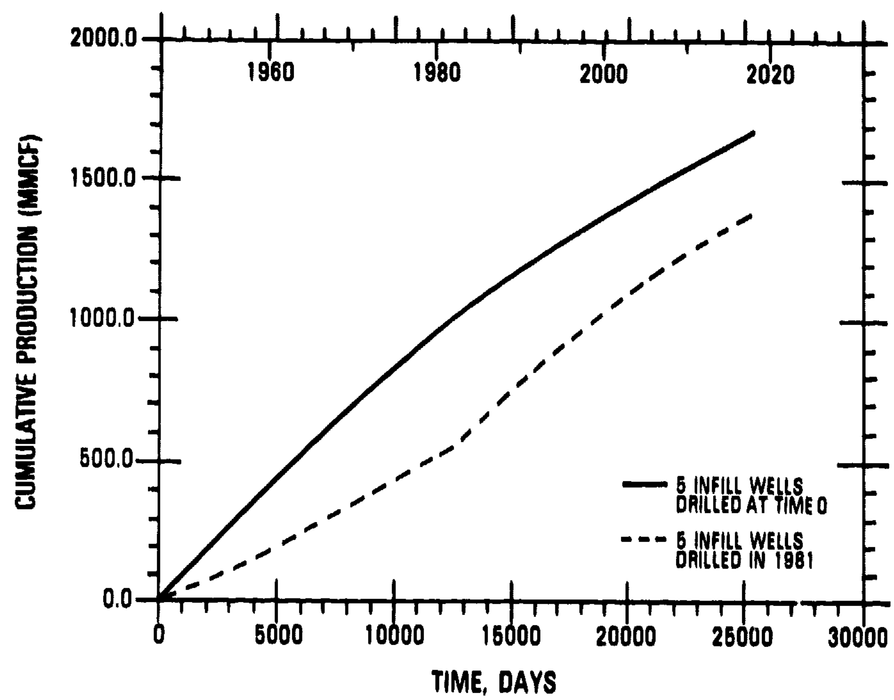

Fig. 10—Impact of five additional wells on four-well portion's 70-year production: infill drilling at $t=0$ vs. $t=35$ years.